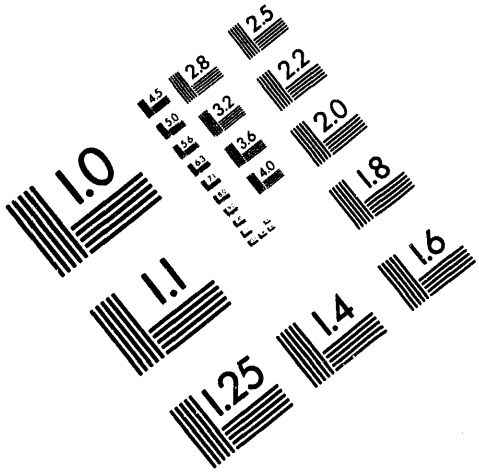

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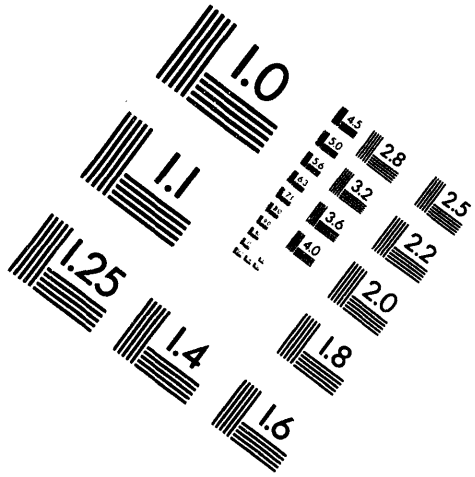

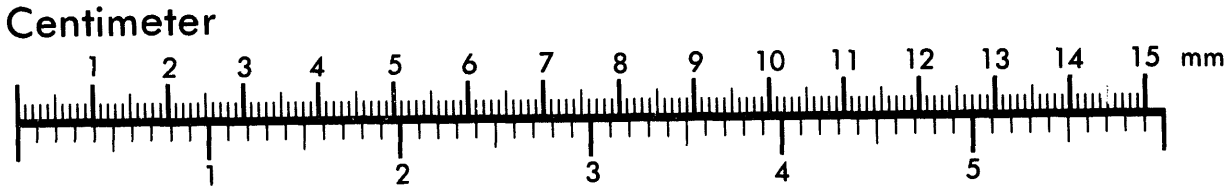

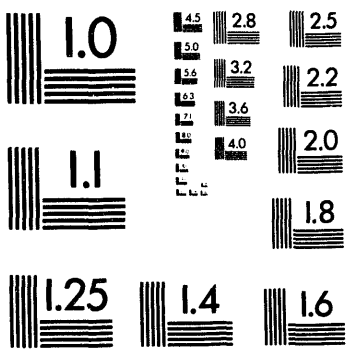

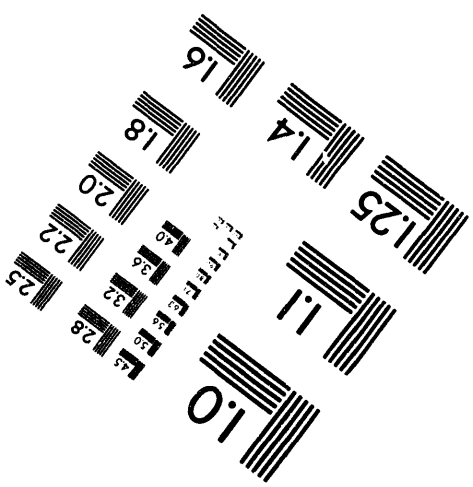

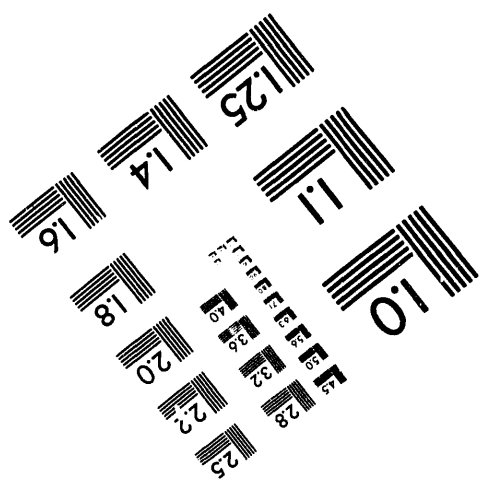

1 of 1

Quarterly Technical Progress Report

IMPROVED TECHNIQUES FOR FLUID DIVERSION IN OIL RECOVERY

Contract Number: DE-AC22-92BC14880

New Mexico Petroleum Recovery Research Center
New Mexico Institute of Mining and Technology
Socorro, New Mexico

Date of Report: April 1, 1994

Contract Date: September 17, 1992

Anticipated Completion Date: September 30, 1995

Program Manager: Randall S. Seright

Principal Investigator: Randall S. Seright

Contracting Officer's Representative: Jerry F. Casteel

Reporting Period: January 1, 1994 through March 31, 1994

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PRRC Report 94-11

DISCLAIMER

OBJECTIVES

This three-year project has two general objectives. The first objective is to compare the effectiveness of gels in fluid diversion with those of other types of processes. Several different types of fluid-diversion processes will be compared, including those using gels, foams, emulsions, and particulates. The ultimate goals of these comparisons are to (1) establish which of these processes are most effective in a given application, and (2) determine whether aspects of one process can be combined with those of other processes to improve performance. Analyses will be performed to assess where the various diverting agents will be most effective (e.g., in fractured vs. unfractured wells, deep vs. near-wellbore applications, reservoirs with vs. without crossflow, or injection wells vs. production wells). Experiments will be performed to verify which materials are the most effective in entering and blocking high-permeability zones. Another objective of the project is to identify the mechanisms by which materials (particularly gels) selectively reduce permeability to water more than to oil. In addition to establishing why this occurs, our research will attempt to identify materials and conditions that maximize this phenomenon.

SUMMARY OF TECHNICAL PROGRESS

Propagation of Gels Through Fractures. Our previous work[1] suggested that under some circumstances, improved fluid diversion in fractured systems might be obtained by injecting pre-formed gels rather than gelants that would form gels in situ. However, for this approach to be successful, the injected gel must be able to propagate through the fractures without "screening out" or developing excessive pressure gradients. We suspect that the ability of a given gel to propagate effectively through a fracture depends on (1) the composition of the gelant, (2) the degree of gelation or gel "curing," (3) the fluid velocity (or pressure gradient) in the fracture, and (4) the width, conductivity and tortuosity of the fracture.

We performed several experiments to probe how the degree of gel "curing" affects flow of a gel through fractured Berea sandstone cores. In these experiments, the sandstone cores had nominal permeabilities to brine of 650 md before fracturing. The cores were 14 cm in length and 3.6 cm in diameter. Preparation of the fractured cores has been described earlier.[1] The third column of Table 1 lists conductivities, $k_f w_f$, for the fractures in each core. For each experiment, we prepared a formulation that contained 0.5% HPAM (Allied Colloids Alcoflood 935®, $Mw \approx 5 \times 10^6$ daltons; degree of hydrolysis: 5-10%), 0.0417% chromium triacetate (Sargent-Welch) and 1% NaCl (pH=6). The gelation time for this composition was roughly 5 hours at 41°C. We injected this gel into our fractured cores after allowing different time periods to elapse. These delay times ranged from 10 to 72 hours (see Column 1 of Table 1). During gel injection, the injection rate was fixed at 200 ml/hr. All experiments were performed at 41°C.

Column 4 in Table 1 suggests that gel resistance factors (apparent gel viscosities in the fractures) increased dramatically with increased curing time up to 32 hours. However, between 32 and 72 hours, the gel resistance factors decreased substantially. An explanation for this decrease must await further research. The pressure gradients in the cores during gel injection are listed in Column 5 of Table 1. Even the lowest pressure gradients raise concern about the practicality of injecting these pre-formed gels unless the fractures have very high conductivities. Hopefully, future work will identify compositions and conditions that will allow gel injection to be feasible.

The second and third entries in Table 1 illustrate the effect of fracture conductivity on gel propagation. For a gel that was aged 24 hours before injection, the resistance factor was about the same in a fracture

with $k_f w_f$=53.8 darcy-cm as that with $k_f w_f$=187 darcy-cm. However, the pressure gradient in the latter case was about one-quarter that in the less conductive fracture.

Table 1. Injection of a Cr(III)-acetate-HPAM Gel into Fractured Cores

Injection delay, hours	Core	$k_f w_f$, darcy-cm	Resistance factor	dp/dl, psi/ft
10	15	64.3	500	35
24	7	53.8	3,000	250
24	8	187.0	2,750	68
32	8	187.0	14,500	357
72	11	44.4	340	34

Disproportionate Permeability Reduction. In our investigation of the ability of gels to reduce permeability to water more than that to oil, virtually all our experiments to date have used high-permeability Berea sandstone cores. The question was raised, "Is the disproportionate permeability reduction sensitive to absolute core permeability or lithology?" To address this question, we conducted oil/water experiments in a low-permeability Berea sandstone core and in an Indiana limestone core. The strongly water-wet low-permeability Berea sandstone core had a nominal absolute permeability to brine of 110 md. The limestone core had a nominal absolute permeability to brine of 30 md. Each core was about 14-cm long and 3.6 cm in diameter with two internal pressure taps located approximately 2 cm from either end of the core. The center core segment was used to measure mobilities and residual resistance factors; whereas, the first and the third segments were used as filters. The gel had a composition of 1.39% polyacrylamide polymer (HPAM), 0.0212% Cr(III) as acetate and 1% NaCl. A refined oil, Soltrol-130® was used as the oil phase. For a given core experiment, the brine used to saturate the core had the same composition as that used for gelant preparation. All experiments were performed at 41°C.

Results from endpoint oil- and water-mobility measurements before gelant injection are summarized in Tables 2 and 3. (Ref. 2 contains a detailed description of the experimental procedure.) For the low-permeability Berea sandstone core, Table 2 shows no hysteresis of endpoint mobilities (either for water or oil) as a result of flow-direction reversal and multiple imbibition and drainage cycles. However, for the limestone core, significant hysteresis of both endpoint water and oil mobilities were observed as a result of flow-direction reversal and multiple imbibition and drainage cycles (Table 3). Also, similar endpoint oil and water mobilities suggest that the limestone core was less water-wet than the sandstone core.

During a given gelant injection process, the gelant was injected into the core using the maximum possible injection rate without exceeding a 200 psi/ft pressure constraint. (The pressure constraint was imposed to avoid mobilizing the residual oil phase during gelant injection.) For the low-permeability Berea sandstone core, we only managed to inject about 0.9 pore volumes of the gelant before the injection rate became unacceptably low. The core was then shut in for about 5 days. After shut-in, water was injected first and residual resistance factors for water (F_{rrw}) were measured at different flow velocities. As shown in Table 4, the residual resistance factors for water exhibited a shear-thinning behavior and could be

described by a power-law equation ($F_{rrw} = 12\ u^{-0.26}$). In order to minimize gel breakdown, the subsequent residual resistance factor measurements were performed using a single injection velocity (1.575 ft/d). Table 4 shows that the permeability reduction for water was only about twice that for oil after treatment. In contrast, the gel in a high-permeability Berea sandstone core reduced water permeability about 30 times more than oil permeability.[2] The low F_{rrw} and F_{rro} values were probably caused by poor gelant propagation in the porous medium.

Table 2. Residual Saturations and Endpoint Mobilities before Gel
(110-md Berea Sandstone Core, 41°C)

Stage	S_{wr}	Endpoint Oil Mobility, md/cp
1st oilflood before gel	0.28	113
2nd oilflood before gel	0.27	112
3rd oilflood before gel*	0.27	119
4th oilflood before gel*	0.28	119
Stage	S_{or}	Endpoint Water Mobility, md/cp
1st waterflood before gel	0.42	29
2nd waterflood before gel	0.43	25
3rd waterflood before gel*	0.43	27
4th waterflood before gel*	0.41	26

* flow direction reversed

Table 3. Residual Saturations and Endpoint Mobilities before Gel
(30-md Indiana Limestone Core, 41°C)

Stage	S_{wr}	Endpoint Oil Mobility, md/cp
1st oilflood before gel	0.36	22
2nd oilflood before gel	0.37	32
3rd oilflood before gel*	0.40	40
4th oilflood before gel*	0.38	46
Stage	S_{or}	Endpoint Water Mobility, md/cp
1st waterflood before gel	0.30	22
2nd waterflood before gel	0.31	27
3rd waterflood before gel*	0.34	36
4th waterflood before gel*	0.36	43

* flow direction reversed

Table 4. Summary of Residual Resistance Factors for Water (F_{rrw}) and for Oil (F_{rro})
(Gel: 1.39% polyacrylamide, 0.0212% Cr(III), and 1% NaCl)

Core	1st F_{rrw}	F_{rro}	2nd F_{rrw}
600-md Berea sandstone	> 35,300	50	$1430\ u^{-0.44}$
110-md Berea sandstone	$12\ u^{-0.26}$	4*	9*
30-md Indiana limestone	$47\ u^{-0.51}$	4	$18\ u^{-0.52}$

* measured at a single flow velocity (1.575 ft/d)

For the limestone core, we were able to inject about 1.8 pore volumes of the gelant before the injection rate became too low under the 200 psi/ft pressure constraint. As shown in Table 4, the residual resistance factors for water were non-Newtonian and could be described by a power-law equation. The flow behavior of oil in the porous medium after treatment was, however, more or less Newtonian. Table 4 shows that water permeability was reduced significantly more than oil permeability after treatment.

Because we were not able to force multiple pore volumes of gelant into the low-permeability sandstone and limestone cores, we cannot yet conclude that permeability and lithology have an important effect on the disproportionate permeability reduction by gels.

References

1. Seright, R.S.: "Gel Placement in Fractured Systems," paper SPE 27740 presented at the 1994 SPE/DOE Symposium on Improved Oil Recovery, Tulsa, OK, April 17-20.

2. Seright, R.S.: "Improved Techniques for Fluid Diversion in Oil Recovery," first annual report, DOE/BC/14880-5, U.S. DOE (Dec. 1993) 141-165.

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